Crossborder Energy

Comprehensive Consulting for the North American Energy Industry

FINAL REPORT

Evaluation of Navigant Consulting's Long-term SDG&E Rate Forecast

Prepared for the City of Chula Vista, California

MARCH 24, 2004

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I. INTRODUCTION AND SUMMARY

This report evaluates a long-term forecast of San Diego Gas and Electric's natural gas and electric rates. Navigant Consulting (Navigant) prepared this forecast as a key component in the municipal energy utility (MEU) feasibility analysis that it prepared for the City of Chula Vista (City). The City has asked us to validate the key assumptions in the forecast and to comment on the reasonableness of the forecast results.

The following are the key conclusions of our review. We separate our findings into those that apply to an electric MEU and those that apply to a natural gas MEU.

<u>Electric MEU</u>

- Navigant's projection of future natural gas prices is a key driver of its forecast of SDG&E's future electric rates. Navigant's long-term forecast of natural gas prices is reasonable, and is within 8% of similar recent forecasts that our firm and the California Energy Commission have prepared. However, Navigant also should perform **sensitivity analyses that reflect California border natural gas prices that are both 20% above and 20% below the levels projected in their study**, in order to bracket the likely range of future gas market conditions and to further refine the analysis. We anticipate that at <u>lower</u> natural gas prices the option for Chula Vista to develop its own gas-fired generation within the City will be <u>more attractive</u> than Navigant portrays. The converse will be true at higher gas prices.

- Navigant's forecast of **natural gas transportation rates on the SoCalGas / SDG&E system is too low**, particularly for electric generators. Navigant's forecast does not reflect the potential end to the Sempra-wide electric generation rate or the possible move to a new cost allocation methodology. Assuming higher natural gas transportation rates for electric generators in the San Diego area would slightly reduce the attractiveness of the City owning its own gas-fired power plant.

- Navigant's forecast of **wholesale electric prices is reasonable**, given current and expected future conditions in the wholesale electric market that serves California. Natural gas prices are the key driver of Navigant's forecast of wholesale electric prices.

- Navigant should verify that it has included **direct access exit fee revenues** as an offset to SDG&E's cost of DWR power. SDG&E direct access loads approach 20% of its overall demand, and thus the utility will derive substantial revenues from its direct access exit fee. We believe that Navigant has included these revenues, but its report is unclear on this point.

- Using reasonable assumptions for SDG&E's resource mix and generation costs, we were able to reproduce Navigant's results, to within one percent, for the generation portion of SDG&E's rates over the period 2006 - 2011. **This validates Navigant's projection of the generation portion of SDG&E's electric rates**.

- **Navigant's long-term inflation forecast is too high by almost 1%.** Assuming a long-term inflation forecast of 2.0% and a productivity factor of 1.5%, **SDG&E's non-generation rates should increase by no more than 0.5%**, significantly less than Navigant's assumed 1.3% annual escalation. Making this change in Navigant's forecast of SDG&E's future electric rates should not change the results of the Community Choice Aggregation (CCA) scenarios (which assume that SDG&E continues to provide non-generation services such as transmission and distribution), but may decrease the economic benefits of the Greenfield Development or full-fledged municipal utility options.

<u>**Natural Gas MEU**</u>

- Navigant erroneously forecasts that Chula Vista's cost to serve a gas-fired power plant within the City would be higher than if SDG&E served the plant. Correcting just this one error indicates that the NPV of a city-owned gas utility is close to zero. We conclude that **a more careful analysis of the potential benefits of a City-owned gas utility is warranted.**

- Navigant's analysis does not consider **the potential benefits of Chula Vista's location close to a potential major new source of liquified natural gas (LNG) supplies** for both upper and lower California. Chula Vista is uniquely situated to realize substantial benefits from its proximity to the LNG terminals proposed to be built in Baja California. If an LNG terminal is developed in Baja, as both Navigant and Crossborder expect to happen, the cost of gas at the Otay Mesa border crossing will be competitive with California / Arizona border prices. In this event, Chula Vista's close proximity to this border crossing should give it the competitive leverage to obtain gas supplies at prices that are significantly lower than supplies moved over the traditional route through the SoCalGas and SDG&E systems. In this scenario, the potential net present value of the benefits of a City-owned gas utility could be in the range of $42 to $73 million (with the range of results depending on future SDG&E gas transportation rates). The City should monitor closely the progress of the proposed LNG terminals and the regulatory developments that will determine how those new gas supplies can reach customers in California. Finally, the potential availability of a low-cost source of natural gas for City-owned gas-fired generation could have a significant beneficial impact on those MEU scenarios.

II. EVALUATION METHOD

A. Constraints

Navigant did not provide us with a copy of the model that it used to prepare its SDG&E rate forecast, due to confidentiality concerns. Navigant's Technical Appendix C, Section II.A, does provide a broad description of how Navigant modeled future SDG&E rates. Because we have not had access to the details of Navigant's model, of necessity our evaluation has focused on the material that is available for our review – the input assumptions used in the model and the output that the model produces. We have also used our own data sources and energy price projections, as well as data on SDG&E's rates produced in various CPUC proceedings. With the data available to us, we have been able to duplicate Navigant's results for the generation component of SDG&E's electric rates, which is the key element of Navigant's projection of future SDG&E rates.

Finally, we recognize that Navigant completed its study in October 2003. As a result, Navigant's projection does not reflect certain recent developments that have occurred in the past several months, after the study was finalized. We indicate below several possible developments that the City may want to include in any future updates to Navigant's work.

B. Caveats

Our work has focused on whether Navigant's SDG&E rate forecast is based on the best available information for the key assumptions that will drive that forecast. The initial draft of our report was prepared in November and December 2003, and reflects market conditions and regulatory developments at that time. Many of the assumptions that both we and Navigant have used involve projections of future prices in energy markets that are volatile and that can change in ways that are difficult to predict. If energy market conditions change significantly, we recommend that the City update and re-visit the results of the Navigant study to reflect the new conditions. We also suggest a number of sensitivity studies that the City may wish to have Navigant perform in order to understand how Navigant's results may change if certain key assumptions are varied. These sensitivity analyses are important if the City is to understand the robustness of Navigant's findings under changing market conditions.

III. KEY ASSUMPTIONS

A. Natural Gas Price Forecast, as a Key Driver of Wholesale Power Costs in California.

Navigant's forecast of delivered natural gas prices in the SDG&E service territory is a key driver of its forecast of the generation component of SDG&E's electric rates. The gas price forecast, including SDG&E and SoCalGas rates to transport gas across their pipeline systems, also plays a key role in Navigant's evaluation of the potential economic benefits of the City's development of a municipal gas utility. The delivered cost of natural gas has two principal components – first, the market price of gas at the California border and, second, the transportation costs required to deliver gas from the border to the end user's burner-tip across various pipeline systems. We evaluate each of these components of Navigant's gas price forecast separately.

1. Natural gas prices at the California/Arizona border.

Navigant forecasts an average California border price of $4.90 per MMBtu for the period from 2006 to 2023. This appears to be a reasonable forecast given today's market outlook and conditions.

To judge the reasonableness of Navigant's forecast, we compare it to other market forecasts. We have assembled our own forecast of gas prices, based on (1) recent prices in the NYMEX Henry Hub, Louisiana gas futures market and (2) our analysis of historical and likely future basis differentials[1] between the Henry Hub and the southern California border. We have also reviewed gas price projections contained in the California Energy Commission's August 2003 *Natural Gas Market Assessment*.

Navigant's forecast was assembled in June 2003, at a time when both spot and futures prices were over $1.00 per MMBtu higher than the November 2003 prices used in our forecast. Nevertheless, Navigant's forecast for California appears to be reflective of recent market conditions in California. This is probably the result of Navigant's assumption of a much larger (negative) basis differential for the southern California border. For example, Figure 2 (page 104)

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[1] The "basis differential" is the price difference for a commodity between a reference market and a market in another location. Thus, the basis differential provides the market value of transporting the commodity between the two markets. In this case, the reference market is the NYMEX gas futures market located at the Henry Hub in Louisiana. The second market is at the Southern California / Arizona border at Topock, Arizona. The basis differential is the difference in prices between the two markets.

of Navigant's Technical Appendix indicates a ($0.66) basis differential (i.e. Henry Hub $5.99 per MMBtu vs. Topock $5.33 per MMBtu) for the period January to June, 2003.

Our current forecast of California border prices in the 2006-2023 time frame averages $5.08 per MMBtu – a 4% increase over Navigant's border price forecast. Our forecast reflects November 2003 futures market conditions.[2] For the basis differential we have assumed ($0.21) per MMBtu, based on the historical relationship between the Henry Hub and Topock over the period from 1994 to 2003. We excluded the natural gas "crisis" year of 2001, which reflected extremely high gas prices and severe pipeline constraints to California.

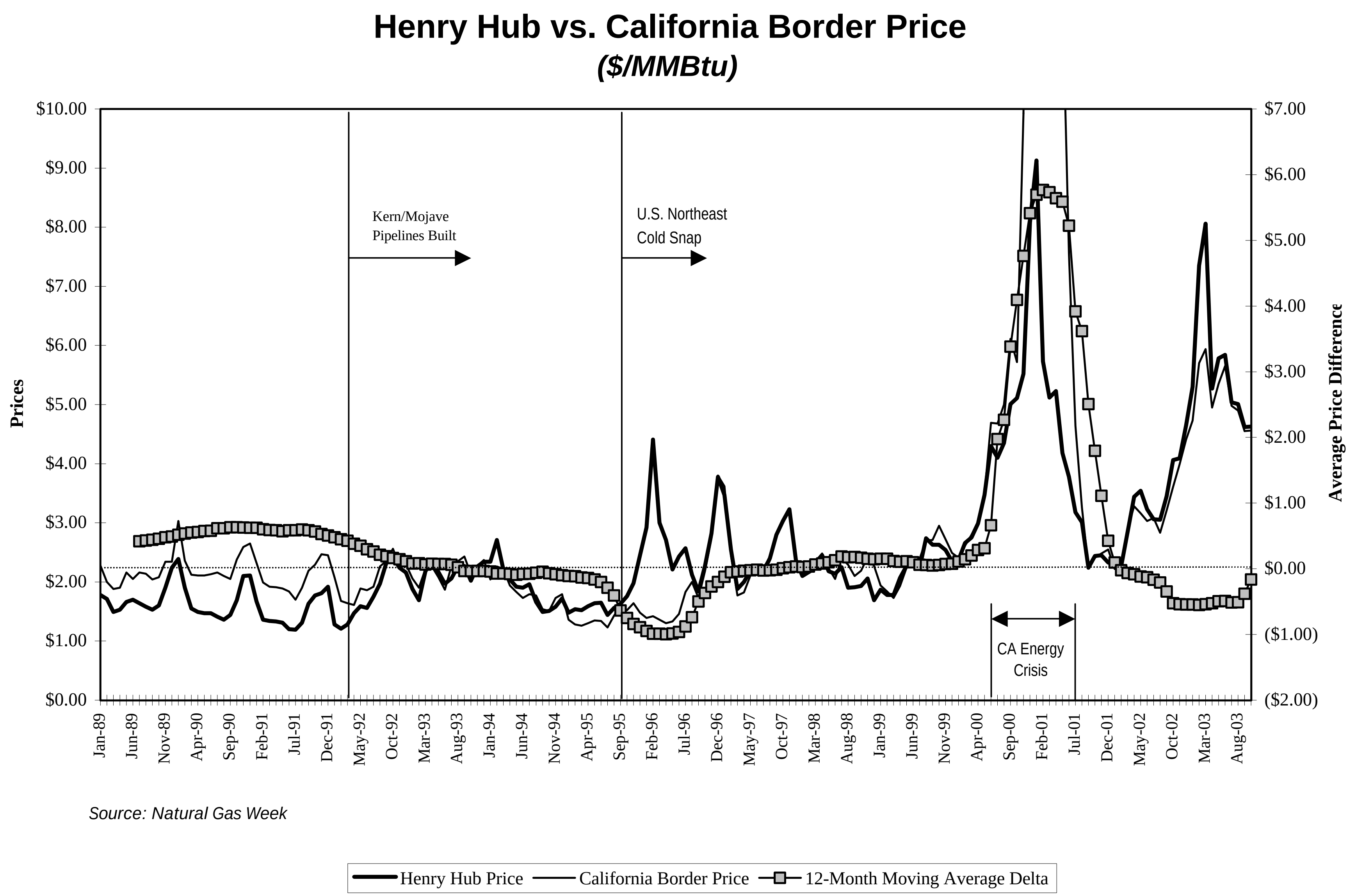
The historical basis differential between the Henry Hub and the southern California border is portrayed in **Figure 1**. Navigant's report also provides a useful summary of historical gas prices and basis differentials. Figure 1 illustrates how high basis differentials have spurred the construction of new pipeline capacity to California. The added capacity then depresses the basis differential until demand growth constrains the pipelines and the basis differential increases. For example, from 1988 - 1993, California border prices exceeded the Henry Hub by $0.39 per MMBtu. After the completion of the 700 MMcf/d Kern River pipeline in March 1992, prices in California decreased to the level of Henry Hub prices, and even fell below the Henry Hub at times. Similarly, the pipeline capacity serving California has expanded by 1.6 Bcf/d since the "basis blow-out" of the 2000 - 2001 energy crisis. As a result, Topock prices today are again at or below the Henry Hub benchmark. With the expected addition of major new LNG supplies to the California market by 2007, we expect basis differentials for the California market to remain low or slightly negative to the Henry Hub. The historical basis differentials are summarized in Table 1, below.

Table 1 – *Historical Gas Prices and Basis Differential*

Period	Henry Hub	Topock	Basis
1989-1993	$1.75	$2.14	$0.39
1994-1996	$2.12	$1.71	($0.41)
1997-1999	$2.29	$2.37	$0.07
2000-2001	$4.15	$7.10	$2.95
2002-2003	$4.34	$4.00	($0.35)

[2] We recognize that gas prices have continued to rise in December 2003. Today's gas futures would support a forecast as much as $0.50 per MMBtu higher than presented here. The recent increases appear to have been driven largely by a major early-winter snowstorm on the Eastern Seaboard that has raised expectations for a colder-than-anticipated winter. We anticipate that prices will moderate as more seasonable weather returns.

Figure 1



Source: Natural Gas Week

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Our forecast of southern California border prices, at Topock, is shown in Table 2. Again, we have used November futures market prices with a ($0.21) per MMBtu basis differential. The average price for the period 2006 to 2023 is $5.08 per MMBtu.

Table 2 – *Crossborder Gas Price Forecast (2003 $ per MMBtu)*

2006	2007	2008	2009	2010	2011	2012	2013	2014
$4.41	4.49	4.50	4.51	4.58	4.68	4.79	4.89	5.00
2015	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**
5.09	$5.20	$5.22	5.40	5.51	5.61	5.72	5.86	$6.01

An additional source of gas price forecasts is the California Energy Commission (CEC), which in August 2003 released its *Natural Gas Market Assessment*. This market assessment includes a gas price forecast in constant 2000 dollars. The CEC forecasts natural gas prices using a large-scale model of gas production, pipelines, and demand across the entire North American continent. When adjusted to 2003 $ per MMBtu, the CEC forecast for Topock for the period 2006 to 2023 is $4.52 per MMBtu. Thus, the CEC forecast is lower than Navigant's forecast by approximately 8%.

We conclude that Navigant's forecast is reasonably close to current price expectations. We do recommend that Navigant prepare sensitivity analyses that reflect natural gas prices that are both 20% above and 20% below the levels projected in Navigant's study. These sensitivity analyses should bracket the likely range of future gas market conditions. Understanding the impacts of the high gas price sensitivity case is particularly important, because we understand that MEU benefits will decline as gas prices increase.

2. Intrastate transportation costs and the fate of the Sempra-wide electric generation rate.

Navigant has assumed a transportation rate of $0.28 per MMBtu for electric generation customers (EG) to move their gas supplies from the California border to their plants on the SDG&E or SoCalGas systems. If the CPUC implements a restructuring of the rates and services on the SoCalGas system known as the Comprehensive Settlement Agreement (CSA), Navigant projects a slightly lower EG rate of $0.24 per MMBtu. As explained below, there are two reasons why we think that these forecasted transportation rates are too low.

An End to the "Sempra-wide" EG Rate. First, Navigant assumes the continuation of the "Sempra-wide" EG rate on the SoCalGas and SDG&E systems. In April 2000, the CPUC made the surprising, and very controversial, decision to equalize transportation rates to electric generation customers on the SoCalGas and SDG&E systems. As both SoCalGas and SDG&E are affiliates of Sempra Energy, the resulting policy is called the "Sempra-wide" EG rate.

Historically, for at least the decade prior to April 2000, EG rates have been much higher on the SDG&E system than on the SoCalGas system, because gas bound for San Diego must flow through the SoCalGas system before reaching SDG&E. EG volumes moving to power plants in San Diego had to pay separate transportation charges on both the SoCalGas and SDG&E systems. This "pancaking" of a SoCalGas wholesale rate plus the SDG&E EG retail rate produced a total rate for power plants in San Diego that was typically $0.15 to $0.20 per MMBtu higher than the retail EG rates paid on the SoCalGas system by EG customers located in the Los Angeles Basin. Electric generators in the San Diego area mounted a major, and successful, campaign in the CPUC's last SoCalGas biennial rate proceeding (BCAP) to remove this rate "pancaking," and to equalize EG rates across all southern California. They argued that all generators in southern California must compete in the same electric market (the California Power Exchange [PX]), and that the "pancaking" of gas rates discouraged the development of much-needed new electric generation in the San Diego area.

Whether to continue the Sempra-wide EG rate will be a major issue in the SoCalGas BCAP that the CPUC will conduct in 2004, to set new rates effective January 1, 2005. The Sempra-wide EG "subsidy" increases SoCalGas' EG rate by about $0.06 per MMBtu, or 12%. We are certain that electric generators in the Los Angeles area will urge the CPUC to end this subsidy of San Diego generators by L.A. generators. In our view, the California energy crisis has undermined the arguments in favor of the Sempra-wide EG rate. The California PX is defunct, and there is no longer a large, centralized electric market out of which the electric utilities must buy all of their power. Furthermore, the California electric utilities have resumed their historic roles of buying the power for their individual service territories. Finally, significant new power plants have been completed or are under construction in the San Diego area and northern Baja California, Mexico. These plants are likely to be served from the new North Baja interstate pipeline and from future liquified natural gas (LNG) supplies. Thus, the need for a special gas rate on the SDG&E system to encourage new generation in the San Diego area is much less pressing today than in 2000.

For these reasons, we believe that there is a 50% chance that the Sempra-wide rate will be repealed effective January 1, 2005. If the Sempra-wide EG rate is eliminated, distinct EG rates for SDG&E and SoCalGas would be established, resulting in an increase in the SDG&E EG rate of as much as an 65%. **Table 3** shows the impacts of repeal of the Sempra-wide EG rate, based on SDG&E's recent BCAP filing (A. 03-09-031, September 17, 2003). The table shows these impacts under both long-run marginal cost (LRMC) and embedded cost rate methodologies, which we discuss in the next section.

Table 3 – *Impact of the Sempra-Wide EG Rate Methodology ($ per MMBtu)*

	LRMC	Embedded
Sempra-wide EG rate	0.43	0.52
SDG&E stand-alone EG rate	0.70	0.75
Increase	0.27	0.23
percent	*65%*	*45%*

A Move to an Embedded Cost Allocation. The second factor that may increase SDG&E's gas transportation rates is a change in the methodology that SDG&E uses to allocate the costs of its gas system among its customer classes. In their recent BCAP filings in September 2003, SDG&E and SoCalGas have asked the CPUC for permission to change their cost allocation methodology. The utilities propose to use an "embedded cost" allocation instead of the current allocation based on long-run marginal costs (LRMC). In essence, this change would shift costs from small "core" customers (residential and small business) to large "noncore" customers such as industrial and electric generation users. In addition, with higher noncore rates under the embedded cost method, the end to the Sempra-wide rate would have a magnified effect.

We believe that there is a 50/50 chance that the CPUC will move to the use of embedded costs. Combining this with a 50% probability of ending the Sempra-wide EG rate, we obtain a projected EG rate for the combined SoCalGas/ SDG&E system of $0.60 per MMBtu. This rate is calculated as an average of the rates shown in Table 3 above. We recognize that this rate includes a large noncore balancing account undercollection that we expect to be amortized by the end of 2005. This undercollection amounts to $0.13 per MMBtu. Thus, our projection of the 2005 SDG&E EG rate excluding this undercollection is $0.47 per MMBtu. This expected SDG&E EG rate is significantly higher than Navigant's assumed EG rate of $0.28 per MMBtu.

3. SoCalGas / SDG&E transportation charges for a City-owned gas utility.

Navigant assumes that a City-owned gas utility would pay a combined SoCalGas/SDG&E transportation rate of $0.41 per MMBtu for service to an electric generation facility in the City (see Pro Forma analysis, page 94). This rate consists of an $0.18 per MMBtu wholesale rate on the SoCalGas system and a $0.23 per MMBtu wholesale rate on the SDG&E system. If SDG&E remains the serving utility, this generator is assumed to pay just the Sempra-wide EG rate of $0.28 per MMBtu. This transportation rate disparity appears to be a major reason why Navigant concludes that it would not be economic for the City to pursue the creation of a gas utility.

We think that this assumed rate disparity is wrong. There is already a precedent for the rate that applies if both SoCalGas and SDG&E transport gas across their systems to an electric generator not on the SDG&E system. This precedent is Sempra's service to the Mexican power plant at Rosarito. The CPUC has required Sempra to charge the Sempra-wide EG rate for this service.[3] There is little difference between this service and the service that SoCalGas and SDG&E would provide to an electric generator in Chula Vista that is served from a City-owned gas system.

Simply correcting this one erroneous assumption produces a significant change in the results of Navigant's *pro forma* analysis of a City-owned gas utility, as shown in **Attachment A** to this report. The net present value (NPV) shown in Navigant's *pro forma* analysis increases by $23 million if the EG rate difference between service from the City versus SDG&E is eliminated. This offsets most of the $24 million NPV in losses assumed by Navigant if a City-owned EG must pay a "pancaked" SoCalGas/SDG&E rate of $0.41 per MMBtu. Moreover, the revised *pro forma* analysis shown in Table 4 indicates that there are benefits for roughly the first nine years. This tells us that a more careful analysis of the potential benefits of a City-owned gas utility is warranted.

4. New LNG supplies will impact gas prices in San Diego.

It should also be emphasized that natural gas prices in the San Diego area could decrease significantly as a function of new LNG supplies entering the California market starting in 2007. Five major energy companies are competing to build an LNG terminal in Baja California, Mexico. Other proposals would site the terminal in Long Beach or offshore from Ventura, California.

Given the number of developers active south of the border, Baja California appears to be the most likely location for the first LNG terminal on the West Coast. An initial LNG terminal would be able to deliver 700 MMcf/d to 1 Bcf/d. From a Baja terminal, LNG supplies could flow either north on the TGN pipeline to the SDG&E system at the Otay Mesa international border crossing, or north and east via the TGN and North Baja pipelines to the El Paso / SoCalGas interconnect at Ehrenberg / Blythe on the California / Arizona border.

SDG&E has indicated that, at minimal cost, it can accept up to 400 MMcf/d of LNG into its system at Otay Mesa for delivery to SDG&E or SoCalGas customers. We also expect 300 MMcf/d to serve Mexican power plant loads in the Tijuana / Mexicali area. LNG would completely displace gas that today flows south and west on the North Baja and SoCalGas / SDG&E systems to serve these San Diego and Mexican markets. Any LNG that does not serve San Diego or Mexican loads could flow east on North Baja to the California / Arizona border market at Blythe.

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3 This policy was established in CPUC D. 99-09-071 (September 16, 1999).

In our opinion, southern California — and San Diego in particular — is clearly the preferred market for LNG from an initial terminal in Baja. LNG would provide a long-sought second source of gas supply for the San Diego area, which has always paid higher rates for gas service due to its location "behind" the SoCalGas system. Both LNG suppliers and consumers should prefer that LNG supplies flow to the Sempra / SDG&E system at Otay Mesa rather than over North Baja to the California/Arizona border market, because the SDG&E option avoids transportation charges on North Baja (on the order of $0.25 per MMBtu). In addition, gas customers in SDG&E's territory would gain a new source of gas supplies that does not require transportation over the SoCalGas system, thus also avoiding SoCalGas' wholesale transportation costs (now about $0.18 per MMBtu, but expected to rise substantially in 2005 as a result of the new SoCalGas BCAP case). An LNG supplier would greatly prefer to sell gas at the Otay Mesa border crossing to a customer in San Diego, where the competing sources of gas are supplies delivered over the SoCalGas system at the California border price <u>plus</u> $0.18 per MMBtu for wholesale transportation on SoCalGas. The LNG supplier's other option (except for local markets in Baja) would be to move gas over North Baja to the California border at Ehrenberg, for which the supplier would receive the California border price <u>minus</u> the $0.25 per MMBtu backhaul charge on North Baja. On a short-term basis, if there is spare capacity to move gas east on North Baja, then the market price in Tijuana may be just slightly below the Topock border price, due to the low market value of North Baja capacity. In sum, although Sempra has yet to establish Otay Mesa as a receipt point for gas flowing into the SDG&E system, we believe that state policymakers would be foolish not to force Sempra to do so, because that is the most direct and most economical means to move new LNG supplies to the southern California market.

Given these market dynamics, if the LNG supplies delivered to a terminal in Baja California exceed the capacity of local markets and the SDG&E system to absorb them, we expect the price for gas at the Otay Mesa border crossing to be less than the southern California border price at Topock, Arizona. LNG supplies would fit into the economic landscape in such a way that the netback price for LNG is equal to the Topock market less the market value of transportation on the North Baja pipeline. Thus, if an LNG terminal is built in Baja California, we expect that gas prices at the Otay Mesa border crossing will be competitive with California / Arizona border prices. Thus, customers in Chula Vista should be able to obtain gas supplies in the Otay Mesa market at prices at or below the benchmark Topock price, and simply pay a transportation charge to SDG&E to deliver this gas (and perhaps a charge for receipt point access at Otay Mesa, as discussed below), thus avoiding the SoCalGas wholesale transportation costs that all customers on the SDG&E system must pay today.

We believe the case described above to be the most likely. However, it should be noted that to the extent LNG supplies initially enter the market in small amounts, or to the extent that LNG supply is initially dominated by a single supplier (e.g. a market power scenario), gas at the Otay Mesa could be priced on a net-forward basis, such that the end-use customer (e.g. Chula Vista) would face a price equal to the California border price <u>plus</u> the market transportation rate on either North Baja or the Sempra system. In this scenario, the customer would be confined to negotiating a small discount to service from the price of otherwise available supplies on the SoCalGas/SDG&E system. We do not expect this scenario to materialize so long as multiple suppliers of LNG and conventional supplies compete with each other to serve customers in the Baja California / San Diego area and a single LNG supplier is not allowed to monopolize the receipt point capacity into the SDG&E system at Otay Mesa.

We also anticipate that SoCalGas and SDG&E will implement a system of firm capacity rights at the receipt points where gas enters the Sempra system. This system may be the CSA that the CPUC is now considering whether to implement,[4] or it may be a revised system of firm rights that is implemented in 2006. Under any such scheme, we expect that there will be a charge for receipt point access into the SDG&E system at Otay Mesa in the range of $0.06 to $0.08 per MMBtu.[5]

Once gas enters the SDG&E system at Otay Mesa, the charge for transportation to end users should be less than the current transportation rates for service over the combined SoCalGas and SDG&E systems. We note that the SDG&E system today provides a rate for transportation only on the SDG&E system to EGs located within San Diego County (Schedule EG-SD) of approximately $0.10 per MMBtu.[6] Even with an additional receipt-point access charge of $0.08 per MMBtu, this rate would be much lower than the current combined SoCalGas / SDG&E EG rate of $0.27 per MMBtu. Thus, to the extent that electric generation in Chula Vista takes gas service from the California/Mexico border, the cost of transportation on the SDG&E system from Otay Mesa should be lower than SDG&E's traditional rates that combine transportation over both the SoCalGas and SDG&E systems. This should remain true even if SDG&E's transportation rates rise in the upcoming BCAP case due to the end to the Sempra-wide subsidy or a change to an embedded cost allocation.

In sum, Navigant's analysis does not consider the potential benefits of Chula Vista's location close to a potential major new source of natural gas supplies for both upper and lower California. We anticipate that the cost of gas at the Otay Mesa border crossing will be

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[4] The CPUC will make this choice early in 2004.

[5] Under the CSA, the charge for firm receipt point capacity is 7.8 c/MMBtu. SoCalGas recently suggested a lower charge of 6 c/MMBtu as one of certain changes to the CSA that it proposed earlier this fall.

[6] This rate currently applies only to deliveries only from the SoCalGas / SDG&E interconnect at Rainbow. We assume that the CPUC also will approve such a rate for deliveries from the international border at Otay Mesa.

competitive with California / Arizona border prices. We also expect that the cost of moving supplies from Otay Mesa to customers on the SDG&E system with be the cost of receipt point access at Otay Mesa plus an unbundled rate for transportation on the SDG&E system alone.

5. Bypass potential in Chula Vista.

The fact that gas prices at the California/Mexico border may be the same as or even lower than prices at the California/Arizona border, once LNG supplies enter the market, presents a bypass opportunity for Chula Vista. Even if the City does not actually build a bypass pipeline, the threat of bypass may exert significant leverage on SDG&E at least to discount its gas transportation rates to the cost of bypass service.

Table 4 presents a preliminary analysis of the possible cost to bypass the SDG&E system via a pipeline to the Otay Mesa border crossing. The distance from the South Bay power plant to the Otay Mesa border crossing is no more than 15 miles. SDG&E local transmission pipelines (eight- and ten-inches in diameter) already run along most of the route (roughly parallel to Highway 905 and Interstate 5). A conservative, order-of-magnitude estimate for the cost of a pipeline to bypass SDG&E's service to South Bay and Chula Vista is $32 million ($2 million per mile plus $2 million for meter stations[7]), for construction in a heavily-developed urban and suburban environment. We have used a Pacific Gas and Electric pipeline cost-of-service model to estimate O&M and A&G costs for operating this pipeline. Consistent with the Navigant study, we assume that the City finances this project over 20 years at an interest rate of 5.5%. With assumed City gas volumes of 90,800 MMBtu per day, or 33,157 M3Btu per year as shown on the gas utility pro-forma, the resulting transportation rate for a City-owned power plant at the South Bay site is $0.14 per MMBtu, which is very competitive even with today's Sempra-wide EG transportation rate of $0.27 per MMBtu. As shown in the revised pro-forma that is **Attachment B**, at a $0.14 per MMBtu rate for 100% of Chula Vista's projected gas loads, plus Navigant's assumed distribution costs within Chula Vista, the NPV benefit of a municipal gas utility is on the order of $73 million assuming our expected SDG&E EG transportation rate of $0.47 per MMBtu. Even using the current Sempra-wide EG rate of $0.27 per MMBtu, which we believe is too low, the gas MEU benefits are $42 million if the City can bypass the SDG&E system.

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[7] We reviewed the costs of PG&E's expected 2004 local transmission pipeline projects (16 to 24-inch pipelines) in its Gas Accord II application to the CPUC (A. 01-10-011). All of these projects had costs that ranged from $1.0 to $2.0 million per mile. To be conservative, we use the upper end of this range. These costs are also consistent with SDG&E system expansion costs reported in the utility's 1999 BCAP case, A. 98-10-031. SDG&E's large Otay Mesa meter station cost $1.3 million in 1999 $.

Table 4

City of Chula Vista
Financial Pro Forma Analysis
Natural Gas Utility Option -- Cost to Bypass SDG&E

Pipeline Capital	$	32,000,000	
Interest		5.5%	
Term		20	*years*
Annual Bond Charge	$	2,677,739	
Annual O&M @ 3.2%	$	1,024,000	
Annual A&G @ 3.0%	$	960,000	
Total Annual Costs	$	4,661,739	
Throughput		33,157	*M3Btu*
		90.8	*M3Btu per day*
Bypass Rate	**$**	**0.141**	*per MMBtu*

B. Wholesale Market Cost of Electric Power

Navigant's electricity spot market forecast for 2006 to 2023 reflects an average price of $49 per MWh. Navigant has told us that they did not use a production cost or market simulation model to forecast electric market prices. Instead, they appear to have calculated wholesale electric prices by applying a market heat rate of approximately 9,000 Btu per kWh, and a variable O&M adder of $2 per MWh, to their burner-tip gas price forecast. This is a common forecasting methodology that reflects the fact that natural gas-fired generation is typically the marginal, market-clearing source of electricity in California.

In 2003 Dow Jones has reported California spot market prices for electricity of roughly $45 per MWh. Gas prices have been high in 2003, however, and thus the "market heat rate" reflected in the Dow Jones day-ahead spot prices has been close to 8,500 Btu/kWh. During the energy crisis of 2000 - 2001, market heat rates were much higher. However, given the determination of both state and federal regulators to avoid similar disasters in the future, we expect capacity reserve margins to be planned so as to avoid price spikes, with most merchant generators depending on long-term contracts to recover average costs. Thus, in this environment, we would expect the market heat rate to remain at values in the range of 8,500 to 9,000 Btu per kWh. This notion is supported by Navigant's own assumptions for the heat rates of new gas-fired combined-cycle plants (7,000 Btu/kWh) versus older, less efficient gas-fired generation (at 10,000 Btu/kWh). As older generation is gradually displaced by newer generation, we would expect the market heat rates to move towards the 7,000 Btu/kWh value slowly over time, assuming that enough new plants are built at least to offset electric load growth.

Thus, we find that Navigant's projection of wholesale electric market prices is reasonable, given its underlying gas price forecast.

C. Cost and Composition of the Utility's Generation Portfolio over Time.

We have reviewed the reasonableness of Navigant's projection of SDG&E's generation costs. Because Navigant did provided a breakdown of its assumed SDG&E resource mix into the volumes and costs for each of its component resources, we did our own projection of SDG&E's likely future resource mix, using both the input data that Navigant provided as well as our own data sources.

1. SONGS

Navigant has used data from SDG&E's 2003 Cost-of-Service case and from the current Southern California Edison (Edison) general rate case to project SDG&E's 20% share of SONGS costs. We have reviewed the sources for this data, and concur that Navigant has used the best available data.

We used data on expected SONGS production from Edison filings before the CPUC.

2. QFs

Navigant used 2002 FERC Form 1 data to project SDG&E's cost of power from the qualifying facilities that sell to SDG&E. Navigant assumes that 67% of SDG&E's QF costs are linked to natural gas prices.

We disagree with Navigant's assumption that QF contract quantities will decrease over time. Navigant cites its October 2002 consultant's report supporting the DWR bond financing (Consultant Report) as the source for this assumption. In the long-term electric procurement plan that SDG&E filed in the summer of 2003 in the CPUC's procurement docket (R. 01-10-024), SDG&E stated that it expects to re-contract with the QFs on its system, when the QFs' original power purchase contracts expire.[8] Most of SDG&E's QF power comes from four large cogeneration facilities. Based on our knowledge of these facilities, we expect that they will continue to operate over the forecast period, particularly if SDG&E continues to be willing to purchase their output. Thus, we have assumed no decline in QF contract quantities over the forecast period. This is a minor change in Navigant's assumptions, as the decline that Navigant has assumed is not great.

We have made our own estimates of Navigant's assumed QF costs over time, based on SDG&E's short-run avoid cost (SRAC) energy pricing formula, which is linked to natural gas prices. We also assumed that SDG&E will pay $20 per MWh in firm capacity payments to its QFs.

3. DWR long-term contract power

As a primary consultant to the DWR, we understand that Navigant has significant expertise modeling the quantities and costs of the DWR long-term contracts. We have used data from the CPUC's exit fee proceeding (R. 02-01-011) on the expected costs and volumes for the DWR contracts assigned to SDG&E.

We are unclear on whether Navigant has included direct access exit fee revenues as an offset to SDG&E's cost of DWR power. This is an important point to verify with Navigant, because SDG&E has a high percentage of direct access loads (approaching 20%) and thus will derive substantial revenues from its direct access exit fee. Our projection of SDG&E's

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[8] *See* "Direct Testimony of Robert J. Resley" filed on behalf of SDG&E in R. 01-10-024 (April 30, 2003), at pages 14-15.

generation rates for bundled customers assumes that exit fee revenues are used to reduce those rates.

4. Inter-utility contracts

Navigant used 2002 FERC Form 1 data to project SDG&E's cost of power from its inter-utility contracts. It is our understanding that these contracts expire at the end of 2003, except for the contract with Portland General Electric (PGE) for a share of the output of the Boardman coal-fired plant in Oregon. We included only the PGE contract in SDG&E's resource mix after 2003.

5. New renewable or gas-fired purchases

California's recently-enacted Renewables Portfolio Standard (RPS) charts an ambitious course for expanding the amount of renewable electric generation in the state. The key element of the RPS legislation, SB 1078, requires the state's investor-owned utilities, including SDG&E, to increase the renewable portion of their energy mix each year by at least 1% of total retail sales, with a goal of 20% renewable generation by 2017. Renewable generation projects will compete with each other to supply the IOUs, with the CPUC establishing a process to select the "least-cost, best fit" projects. If the costs of new renewable power exceeds certain CPUC-established benchmark prices, the above-benchmark costs will be paid from a limited pool of "public goods" funds (which ratepayers also pay as a surcharge on all utility rates). Ratepayers will pay directly for the costs of new renewables up to the benchmark price.

Unlike the two larger electric IOUs, SDG&E's resource portfolio today has little renewable power. We understand that SDG&E has already signed a number of power purchase contracts with new renewable projects, mostly wind farms. According to a recent CEC report,[9] even considering these recent purchases, SDG&E still will need to almost quadruple the amount of renewable power that it expects to buy in 2004 in order to meet the RPS standard of 20% renewable supplies by 2017. Thus, SDG&E will need to devote a significant portion of its resource portfolio to purchases from new renewables.

Navigant's forecast does not appear to consider SDG&E's required renewable purchases separately from its market purchases, although Navigant does model renewable contracts as a potential source of supply for the possible MEU. Navigant assumes that new renewable contracts will be priced at $3 per MWh above the cost of comparable, generic wholesale power (Appendix C, page 65). Navigant based this premium on a study of "green ticket" prices for renewable power reported by the Automated Power Exchange (APX).

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[9] CEC, "Renewable Resources Development Report" (November, 2003), at 6. This report is available at www.energy.ca.gov/reports/2003-11-24_500-03-080F.PDF.

6. Sempra-owned generation

Navigant completed its study for the City prior to SDG&E's announcements that, first, it has negotiated a long-term power purchase agreement for the output of Calpine's 510 MW Otay Mesa power plant and, second, SDG&E plans to acquire the 500 MW Palomar project in Escondido from its Sempra affiliate. SDG&E will operate Palomar as a utility-owned resource. This acquisition of more than 1,000 MW of efficient, local, combined-cycle generation will significantly reduce SDG&E's need to import power from markets outside of its service territory.

This new gas-fired generation will displace market purchases in SDG&E's generation portfolio. Generally, Navigant's assumed cost of wholesale power, based on a market heat rate of 9,000 Btu per kWh and an O&M adder of $2 per MWh, is lower than the "all-in" costs of a new combined cycle plant such as Otay Mesa or Palomar. If SDG&E proceeds to buy power at cost from Palomar and / or Otay Mesa, SDG&E's generation costs may well be higher than Navigant has assumed.

7. Market purchases for the residual net short

Navigant has assumed that SDG&E will purchase power at market prices for its "residual net short" — the difference between its system demand and the power produced by the resources that it owns or has under long-term contract (also known as "utility-retained generation" or URG). In Navigant's model URG appears to include SDG&E's share of SONGS, QF power, existing interutility contracts, and the DWR contracts allocated to SDG&E. We are uncertain whether Navigant considered the purchase of renewable power under the RPS program. As noted in Section III.B above, we concur with Navigant's forecast of wholesale power prices for the market purchases that SDG&E will make to fill its net short requirements.

8. Resource Mix

We have reproduced Navigant's projection of the generation component of SDG&E's rates, using the SDG&E energy balance for 2006 - 2011 contained in the Navigant Consultant Report. This shows SDG&E's future energy mix as a combination of SDG&E's share of SONGS, QF power, the PGE interutility contract, SDG&E's allocated DWR contracts, and market purchases for the residual net short. The consultant report also shows SDG&E's expected amounts of direct access loads.

9. Average Generation Rates

Using the resource mix from the Consultant's Report, we have estimated SDG&E's average generation rate for 2006 - 2011. We have used SONGS costs from the SDG&E cost-of-service case, our own projection of QF costs, PGE contract costs based on 2002 FERC Form 1 data, and the DWR contract costs that Navigant projected in Scenario 14 of the CPUC direct access exit fee case (R. 02-01-011), which Navigant references on page 73 of Appendix C.[10] The CPUC's D. 03-07-030 found this to be the "most reasonable" scenario for future exit fees.[11] We have also assumed that the exit fee revenues based on Scenario 14 are used to reduce SDG&E's generation rates for bundled customers. We priced the utility's residual net short purchases at Navigant's assumed wholesale power costs (without a premium for new renewable purchases).

Under these assumptions, which we believe are reasonable, we were able to reproduce Navigant's results (to within one percent) for the generation portion of SDG&E's rates over the period 2006 - 2011.[12] In our opinion, this validates Navigant's projection of the generation portion of SDG&E's electric rates.

D. Non-Generation Rates

Navigant has taken a simple approach to projecting the non-generation portion of SDG&E's rates. These include transmission, distribution, and public purpose program costs. Navigant has assumed that these portions of SDG&E's rates will escalate at 1.3% per year from a base of the existing June 2003 non-generation rates.

Navigant appears to assume that SDG&E's non-generation rates will continue to be set under a performance-based ratemaking (PBR) program. Since the mid-1990s, the CPUC has used such programs to set the non-generation rates for the California energy utilities. Essentially, a PBR program replaces the traditional biennial or triennial general rate case with a pre-set formula that allows the utility to change its rates (or its allowed revenue requirement) every year by an inflation factor less an assumed productivity rate. PBR programs are intended to provide the utility with a strong incentive to operate efficiently, by allowing shareholders to keep a significant share of the savings if the utility can reduce its costs below those allowed under the PBR formula. The assumption that SDG&E will continue to operate under a PBR mechanism

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[10] We adjusted these DWR contract costs based on the difference between the gas price forecast used in R. 02-01-011 and our own gas price forecast prepared for this report.

[11] We concur in this CPUC finding, which is consistent with the position that we took in this case on behalf of the California Manufacturers & Technology Association.

[12] Navigant does not provide a table showing its forecast for the generation portion of SDG&E's rates. However, we were able to derive them by taking the difference between Navigant's forecast of bundled SDG&E rates and its projection of SDG&E's non-generation rates shown in the Community Choice Aggregation *pro formas*.

simplifies the forecasting of future non-generation rates, because one can use available inflation forecasts and productivity projections.

However, it is important to recognize that, since the California energy crisis, the CPUC has been moving away from the use of PBR mechanisms. In fact, the Commission has required all of the major energy utilities, including SDG&E, to file new general rate cases or cost-of-service proceedings. It is unclear whether the CPUC intends to move back to standard rate cases at regular intervals or simply to use the results of the new rate cases to set new base years for renewed PBR mechanisms.

In the pending SDG&E cost-of-service case, the utility has proposed to return to the use of a PBR mechanism with the results of the current case setting the base year rates. SDG&E has also proposed an inflation index and a productivity factor of 0.52%. Navigant appears to have derived its assumed escalation rate of 1.3% as the difference between an inflation forecast of 2.9% and the utility's currently adopted 1.6% productivity factor under its existing PBR mechanism.

We note that Navigant has used this 1.3% escalation rate for all of SDG&E's non-generation costs, including transmission, distribution, and public purpose program costs, even though SDG&E's PBR program applies only to the utility's distribution costs. Transmission costs are now FERC-regulated and are set in FERC transmission rate cases. However, SDG&E's distribution costs are much larger than its transmission or public purpose program costs, and it does not appear unreasonable to apply the escalation rate for electric distribution to all three cost categories.

1. Inflation rate

Navigant appears to assume a long-term inflation rate for electric distribution costs of 2.9%. Navigant told us that this figure is taken from SDG&E's cost-of-service testimony, which shows both historical and forecasted inflation rates from 1997 - 2004. Our review of that data could not verify the source for the 2.9% figure. The closest number appears to be SDG&E's assumed inflation rate for 2004 — 3.1%. However, we note that the 3.1% inflation assumed for 2004 is high by recent historical standards. SDG&E's longer-term average inflation rate from 1997 - 2004 is 2.2%; over this same period general inflation (the GDP implicit price deflator) has risen by less than 2% per year, and long-term inflation forecasts going forward are now in the 2.0% range. Thus, we believe that Navigant's long-term inflation forecast is high by almost 1%.

2. Productivity assumptions

Navigant used the Commission's currently-authorized productivity adjustment of 1.62% for SDG&E's electric distribution system. The Commission adopted this figure in D. 99-05-030.

SDG&E is proposing a much lower figure, 0.52%, in its pending cost-of-service case. This figure is based on national electric utility productivity trends. Generally, however, the CPUC has adopted productivity adjustments for PBR mechanisms that include a "stretch" factor above industry productivity trends. These "stretch" factors are typically in the range of 0.5% to 1.5%. As a result, Navigant's use of the current 1.62% productivity adjustment appears to include a "stretch" factor of about 1.1%. SDG&E argues in its cost-of-service case that productivity improvements will be more difficult in the future, and thus the CPUC should no longer adopt "stretch" factors. Nonetheless, given the continued strong growth of productivity in the U.S. economy, we anticipate that the CPUC will continue to adopt "stretch" factors of 1.0% and overall productivity factors of 1.5%.

3. Conclusion

With a long-term inflation forecast of 2.0% and a productivity factor of 1.5%, we expect SDG&E's non-generation rates to increase by no more than 0.5%, significantly less than Navigant's assumed 1.3%. Making this change in Navigant's forecast of SDG&E's future electric rates should not change the results of Navigant's Community Choice Aggregation (CCA) scenarios, which assume that SDG&E continues to provide non-generation services such as transmission and distribution. However, a lower forecast of SDG&E transmission and distribution rates should decrease the economic benefits of the scenarios in which the City provides these non-generation services (i.e. the Greenfield Development or full-fledged municipal utility options).

E. Other Rate Elements

Navigant's forecast also includes several other rate elements. First, SDG&E is still amortizing the electric procurement cost undercollection that it accumulated during the energy crisis. This is known as the "AB 265 undercollection," after the legislation that required SDG&E to freeze its rates during the crisis. Navigant expects SDG&E to complete the amortization of this undercollection by the end of 2004. We have reviewed Navigant's assumptions, and agree with this projection.

Second, SDG&E's rates now include the repayment of the bonds that were issued to provide small ratepayers with a 10% rate reduction under the electric restructuring program. These so-called "Fixed Transition Amounts" are expected to expire in 2007. As the amount of these bonds is fixed and the repayment is relatively certain, we do not disagree with this forecast element.

IV. OTHER POSSIBLE FACTORS AFFECTING SDG&E'S RATES

There are several factors that could have a significant impact on a long-range SDG&E rate forecast that Navigant did not consider explicitly. This section discusses these factors.

A. Changes in Cost Allocation among the Customer Classes

Navigant's forecast of non-generation rates is based on escalating the June 2003 non-generation rate components for each of SDG&E's rate schedules. Implicit in this method is the assumption that the allocation of costs between the various customer classes will not change over time. Obviously, it is difficult to forecast such changes. Such changes are less likely if there are no obvious inequities in SDG&E's rate structure. As an example of such an inequity, we cite Southern California Edison's current cost allocation, which now results in large commercial rates that are higher than residential and small commercial rates. Based on our experience in electric rate design, we do not see any such obvious inequities in SDG&E's current rate structure.

We also note that the mix of electric customers in Chula Vista is very similar to the overall mix in SDG&E's service territory, as shown in the table on page 8 of Section II of the main Navigant study. As a result, SDG&E is unlikely to be able to use changes in its cost allocation as a means to reduce the City's incentive to pursue a municipal utility. We conclude that this similarity will minimize the impact of future cost allocation changes on the overall economics of the City's pursuit of its own utility system.

B. Changes in Rate Design Methodology

Navigant's analysis seems to use class average electric rates. Class average rates are influenced not only by the underlying cost allocation, but also by the rate design used to recover costs. Rate design changes that shift costs between fixed monthly charges, demand charges, and energy rates can change class average rates. As an example, Southern California Edison has floated a proposal in the rate design phase of its ongoing general rate case to make a major shift to recover more costs through fixed monthly charges. This proposal has met stiff resistance, and Edison recently backed away from it. With no major shifts in SDG&E's rate design on the horizon, it is our judgement that Navigant's use of class average rates is reasonable.

We conclude that Navigant made reasonable assumptions concerning cost allocation and rate design on the SDG&E system. However, the City may need to re-evaluate the economics of its MEU endeavors if SDG&E makes significant rate changes in the future.

Attachment A

City of Chula Vista
Financial Pro Forma Analysis
Natural Gas Utility Option
(No Cost Penalty to Serve EGs)

	NPV	2002	2003	2004	2005	2006
Customer Accounts						
Residential		62,500	64,925	67,349	69,774	72,199
Core Commercial		3,370	3,411	3,513	3,735	3,784
Noncore Commercial		20	20	21	22	22
Noncore Industrial		10	10	10	10	10
Electric Generation		1	1	1	1	1
Total		65,901	68,367	70,894	73,542	76,016
Gas Requirements (Mth)						
Residential		20,600	21,293	21,977	22,655	23,395
Core Commercial		6,366	6,475	6,702	7,161	7,291
Noncore Commercial		5,000	5,086	5,264	5,625	5,727
Noncore Industrial		34,778	34,778	34,778	34,778	34,778
Subtotal R/C/I		66,744	67,632	68,721	70,219	71,191
Electric Generation		110,184	113,489	116,894	120,401	124,013
Total		176,928	181,121	185,615	190,620	195,204
% Increase			2.4%	2.5%	2.7%	2.4%
Estimated SDG&E Delivery Rates ($/Therm) (including SoCalGas charges)						
Residential		0.394	0.429	0.436	0.443	0.451
Core Commercial		0.420	0.405	0.412	0.419	0.426
Noncore Commercial		0.078	0.088	0.089	0.091	0.092
Noncore Industrial		0.078	0.088	0.089	0.091	0.092
Electric Generation		0.019	0.027	0.028	0.028	0.029
change				*1.7%*	*1.7%*	*1.7%*
Estimated SDG&E Non-Gas Revenue ($000) (including SoCalGas charges)						
Residential		$8,112	$9,129	$9,580	$10,040	$10,541
Core Commercial		$2,671	$2,625	$2,762	$3,000	$3,106
Noncore Commercial		$388	$446	$469	$510	$528
Noncore Industrial		$2,700	$3,050	$3,101	$3,153	$3,206
Subtotal R/C/I		$13,871	$15,250	$15,912	$16,703	$17,381
Average R/C/I ($/Therm)		0.208	0.225	0.232	0.238	0.244
Electric Generation		$2,093	$3,118	$3,265	$3,419	$3,580
Total		$15,964	$18,368	$19,177	$20,122	$20,961
Averge ($/Therm)		$0.090	$0.101	$0.103	$0.106	$0.107
Estimated Chula Vista Operating Expenses (including SoCalGas charges with no cost penalty to serve EGs)						
C.V. Delivery Cost to R/C/I			0.152	0.157	0.161	0.166
C.V. Cost to Serve R/C/I ($000)			$10,294	$10,774	$11,339	$11,841
Est. Cost to Serve Power Plant ($/Th)			0.0010	0.0010	0.0011	0.0011
C.V. Cost to Serve PP ($000)	$1,998		$113	$120	$128	$136
SoCalGas Wholesale Rate ($/Th)			0.018	0.018	0.018	0.0184
Est. SDG&E Trans. Rate ($/Th)			0.023	0.023	0.024	0.024
Total Rate R/C/I SoCal & SDG&E ($/Th)			0.041	0.041	0.042	0.043
Total EG Rate SoCal & SDG&E ($/Th)			0.027	0.028	0.028	0.029
SoCalGas/SDG&E Cost to C.V.			**$5,867**	**$6,104**	**$6,369**	**$6,621**
Capital Expense ($000)			$418	$418	$418	$418
Capital Improvement Cost ($000)			$958	$958	$958	$958
Total Expenses			$17,650	$18,374	$19,212	$19,974
Total $/Therm			0.097	0.099	0.101	0.102
Estimated Benefit of Gas Utility						
SDG&E Revenue minus CV Cost	$6,087		$718	$803	$910	$987
Lost Franchise Fee	$7,244		$657	$681	$689	$709
Net Benefit/(Cost)	($1,157)		$61	$122	$221	$278
Discount Rate	9.73%					

Attachment A

City of Chula Vista
Financial Pro Forma Analysis
Natural Gas Utility Option
(No Cost Penalty to Serve EGs)

	2007	2008	2009	2010	2011	2012
Customer Accounts						
Residential	74,624	76,643	78,663	80,683	81,248	81,813
Core Commercial	3,833	3,882	3,954	4,045	4,069	4,092
Noncore Commercial	23	23	23	24	24	24
Noncore Industrial	10	10	10	10	10	10
Electric Generation	1	1	1	1	1	1
Total	78,491	80,559	82,651	84,763	85,352	85,940
Gas Requirements (Mth)						
Residential	24,132	24,786	25,439	26,092	26,275	26,457
Core Commercial	7,422	7,556	7,734	7,952	8,038	8,125
Noncore Commercial	5,830	5,935	6,075	6,246	6,314	6,382
Noncore Industrial	34,778	34,778	34,778	34,778	34,778	34,778
Subtotal R/C/I	72,162	73,055	74,026	75,068	75,405	75,742
Electric Generation	0	0	257,544	257,544	257,544	257,544
Total	72,162	73,055	331,570	332,612	332,949	333,286
% Increase	-63.0%	1.2%	353.9%	0.3%	0.1%	0.1%
Estimated SDG&E Delivery Rates ($/Therm)						
Residential	0.458	0.466	0.473	0.481	0.489	0.497
Core Commercial	0.433	0.440	0.448	0.455	0.462	0.470
Noncore Commercial	0.094	0.095	0.097	0.098	0.100	0.102
Noncore Industrial	0.094	0.095	0.097	0.098	0.100	0.102
Electric Generation	0.029	0.030	0.030	0.031	0.031	0.032
change	*0.5%*	*3.4%*	*1.1%*	*1.7%*	*1.6%*	*1.6%*
Estimated SDG&E Non-Gas Revenue ($000)						
Residential	$11,054	$11,542	$12,043	$12,558	$12,850	$13,147
Core Commercial	$3,214	$3,327	$3,462	$3,618	$3,716	$3,817
Noncore Commercial	$546	$565	$588	$615	$632	$649
Noncore Industrial	$3,259	$3,313	$3,368	$3,424	$3,479	$3,535
Subtotal R/C/I	$18,073	$18,747	$19,461	$20,215	$20,677	$21,148
Average R/C/I ($/Therm)	0.250	0.257	0.263	0.269	0.274	0.279
Electric Generation	$0	$0	$7,812	$7,942	$8,070	$8,200
Total	$18,073	$18,747	$27,273	$28,157	$28,747	$29,348
Averge ($/Therm)	$0.250	$0.257	$0.082	$0.085	$0.086	$0.088
Estimated Chula Vista Operating Expenses						
C.V. Delivery Cost to R/C/I	0.171	0.176	0.182	0.187	0.193	0.199
C.V. Cost to Serve R/C/I ($000)	$12,363	$12,891	$13,454	$14,053	$14,539	$15,042
Est. Cost to Serve Power Plant ($/Th)	0.0011	0.0011	0.0012	0.0012	0.0013	0.0013
C.V. Cost to Serve PP ($000)	$0	$0	$308	$317	$326	$336
SoCalGas Wholesale Rate ($/Th)	0.019	0.019	0.019	0.020	0.020	0.020
Est. SDG&E Trans. Rate ($/Th)	0.025	0.025	0.025	0.026	0.026	0.027
Total Rate R/C/I SoCal & SDG&E ($/Th)	0.043	0.044	0.045	0.046	0.046	0.047
Total EG Rate SoCal & SDG&E ($/Th)	0.029	0.030	0.030	0.031	0.031	0.032
SoCalGas/SDG&E Cost to C.V.	**$3,133**	**$3,225**	**$11,134**	**$11,367**	**$11,565**	**$11,768**
Capital Expense ($000)	$418	$418	$418	$418	$418	$418
Capital Improvement Cost ($000)	$958	$958	$958	$958	$958	$958
Total Expenses	$16,872	$17,492	$26,272	$27,113	$27,806	$28,522
Total $/Therm	0.234	0.239	0.079	0.082	0.084	0.086
Estimated Benefit of Gas Utility						
SDG&E Revenue minus CV Cost	$1,201	$1,255	$1,001	$1,044	$941	$826
Lost Franchise Fee	$650	$679	$858	$885	$905	$924
Net Benefit/(Cost)	$551	$576	$143	$159	$36	($98)
Discount Rate						

Attachment A

City of Chula Vista
Financial Pro Forma Analysis
Natural Gas Utility Option
(No Cost Penalty to Serve EGs)

	2013	2014	2015	2016	2017	2018
Customer Accounts						
Residential	82,378	82,944	83,509	84,074	84,640	85,205
Core Commercial	4,116	4,190	4,377	4,413	4,449	4,485
Noncore Commercial	24	25	26	26	26	27
Noncore Industrial	10	10	10	10	10	10
Electric Generation	1	1	1	1	1	1
Total	86,529	87,170	87,923	88,524	89,126	89,728
Gas Requirements (Mth)						
Residential	26,640	26,823	27,006	27,189	27,371	27,554
Core Commercial	8,212	8,402	8,822	8,938	9,056	9,175
Noncore Commercial	6,450	6,600	6,930	7,021	7,113	7,207
Noncore Industrial	34,778	34,778	34,778	34,778	34,778	34,778
Subtotal R/C/I	76,080	76,603	77,536	77,926	78,318	78,714
Electric Generation	257,544	257,544	257,544	257,544	257,544	257,544
Total	333,624	334,147	335,080	335,470	335,862	336,258
% Increase	0.1%	0.2%	0.3%	0.1%	0.1%	0.1%
Estimated SDG&E Delivery Rates ($/Therm)						
Residential	0.505	0.513	0.521	0.530	0.538	0.547
Core Commercial	0.477	0.485	0.493	0.501	0.509	0.517
Noncore Commercial	0.103	0.105	0.107	0.108	0.110	0.112
Noncore Industrial	0.103	0.105	0.107	0.108	0.110	0.112
Electric Generation	0.032	0.033	0.033	0.034	0.034	0.035
change	*1.6%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*
Estimated SDG&E Non-Gas Revenue ($000)						
Residential	$13,451	$13,761	$14,078	$14,401	$14,730	$15,067
Core Commercial	$3,920	$4,075	$4,348	$4,476	$4,607	$4,743
Noncore Commercial	$666	$693	$739	$761	$783	$806
Noncore Industrial	$3,592	$3,650	$3,709	$3,768	$3,829	$3,890
Subtotal R/C/I	$21,629	$22,179	$22,874	$23,406	$23,949	$24,506
Average R/C/I ($/Therm)	0.284	0.290	0.295	0.300	0.306	0.311
Electric Generation	$8,332	$8,466	$8,602	$8,740	$8,880	$9,023
Total	$29,961	$30,645	$31,476	$32,146	$32,829	$33,529
Averge ($/Therm)	$0.090	$0.092	$0.094	$0.096	$0.098	$0.100
Estimated Chula Vista Operating Expenses						
C.V. Delivery Cost to R/C/I	0.205	0.211	0.217	0.224	0.230	0.237
C.V. Cost to Serve R/C/I ($000)	$15,563	$16,140	$16,827	$17,418	$18,031	$18,666
Est. Cost to Serve Power Plant ($/Th)	0.0013	0.0014	0.0014	0.0015	0.0015	0.0016
C.V. Cost to Serve PP ($000)	$346	$357	$367	$378	$390	$401
SoCalGas Wholesale Rate ($/Th)	0.021	0.021	0.021	0.022	0.022	0.022
Est. SDG&E Trans. Rate ($/Th)	0.027	0.027	0.028	0.028	0.029	0.030
Total Rate R/C/I SoCal & SDG&E ($/Th)	0.048	0.049	0.049	0.050	0.051	0.052
Total EG Rate SoCal & SDG&E ($/Th)	0.032	0.033	0.033	0.034	0.034	0.035
SoCalGas/SDG&E Cost to C.V.	**$11,973**	**$12,191**	**$12,433**	**$12,652**	**$12,875**	**$13,103**
Capital Expense ($000)	$418	$418	$418	$418	$418	$418
Capital Improvement Cost ($000)	$958	$958	$958	$958	$958	$958
Total Expenses	$29,258	$30,064	$31,003	$31,824	$32,672	$33,546
Total $/Therm	0.088	0.090	0.093	0.095	0.097	0.100
Estimated Benefit of Gas Utility						
SDG&E Revenue minus CV Cost	$703	$581	$473	$322	$157	($17)
Lost Franchise Fee	$938	$956	$978	$989	$1,002	$1,031
Net Benefit/(Cost)	($235)	($375)	($505)	($667)	($845)	($1,048)
Discount Rate						

Attachment A

City of Chula Vista
Financial Pro Forma Analysis
Natural Gas Utility Option
(No Cost Penalty to Serve EGs)

	2019	2020	2021	2022	2023
Customer Accounts					
Residential	85,770	86,335	86,496	86,656	86,816
Core Commercial	4,521	4,556	4,599	4,642	4,685
Noncore Commercial	27	27	27	28	28
Noncore Industrial	10	10	10	10	10
Electric Generation	1	1	1	1	1
Total	90,329	90,929	91,133	91,337	91,540
Gas Requirements (Mth)					
Residential	27,737	27,920	27,972	28,023	28,075
Core Commercial	9,295	9,414	9,550	9,687	9,827
Noncore Commercial	7,301	7,395	7,501	7,609	7,719
Noncore Industrial	34,778	34,778	34,778	34,778	34,778
Subtotal R/C/I	79,111	79,507	79,801	80,097	80,399
Electric Generation	257,544	257,544	257,544	257,544	257,544
Total	336,655	337,051	337,345	337,641	337,943
% Increase	0.1%	0.1%	0.1%	0.1%	0.1%
Estimated SDG&E Delivery Rates ($/Therm)					
Residential	0.556	0.564	0.574	0.583	0.592
Core Commercial	0.525	0.534	0.542	0.551	0.560
Noncore Commercial	0.114	0.115	0.117	0.119	0.121
Noncore Industrial	0.114	0.115	0.117	0.119	0.121
Electric Generation	0.036	0.036	0.037	0.037	0.038
change	*1.6%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*
Estimated SDG&E Non-Gas Revenue ($000)					
Residential	$15,410	$15,760	$16,042	$16,329	$16,621
Core Commercial	$4,882	$5,024	$5,178	$5,336	$5,500
Noncore Commercial	$830	$854	$880	$907	$935
Noncore Industrial	$3,953	$4,016	$4,080	$4,146	$4,212
Subtotal R/C/I	$25,075	$25,654	$26,180	$26,718	$27,268
Average R/C/I ($/Therm)	0.317	0.323	0.328	0.334	0.339
Electric Generation	$9,167	$9,314	$9,463	$9,615	$9,769
Total	$34,242	$34,968	$35,643	$36,333	$37,037
Averge ($/Therm)	$0.102	$0.104	$0.106	$0.108	$0.110
Estimated Chula Vista Operating Expenses					
C.V. Delivery Cost to R/C/I	0.244	0.252	0.259	0.267	0.275
C.V. Cost to Serve R/C/I ($000)	$19,323	$20,002	$20,679	$21,378	$22,102
Est. Cost to Serve Power Plant ($/Th)	0.0016	0.0017	0.0017	0.0018	0.0018
C.V. Cost to Serve PP ($000)	$413	$426	$438	$452	$465
SoCalGas Wholesale Rate ($/Th)	0.023	0.023	0.024	0.024	0.024
Est. SDG&E Trans. Rate ($/Th)	0.030	0.030	0.031	0.031	0.032
Total Rate R/C/I SoCal & SDG&E ($/Th)	0.053	0.054	0.054	0.055	0.056
Total EG Rate SoCal & SDG&E ($/Th)	0.036	0.036	0.037	0.037	0.038
SoCalGas/SDG&E Cost to C.V.	**$13,333**	**$13,568**	**$13,801**	**$14,039**	**$14,280**
Capital Expense ($000)	$418	$418	$418	$418	$418
Capital Improvement Cost ($000)	$958	$958	$958	$958	$958
Total Expenses	$34,445	$35,372	$36,294	$37,245	$38,223
Total $/Therm	0.102	0.105	0.108	0.110	0.113
Estimated Benefit of Gas Utility					
SDG&E Revenue minus CV Cost	($203)	($404)	($651)	($912)	($1,186)
Lost Franchise Fee	$1,055	$1,078	$1,104	$1,133	$1,146
Net Benefit/(Cost)	($1,258)	($1,482)	($1,755)	($2,045)	($2,332)
Discount Rate					

Attachment B

City of Chula Vista
Financial Pro Forma Analysis
Natural Gas Utility Option
(SDG&E System Bypass)

	NPV	2002	2003	2004	2005	2006
Customer Accounts						
Residential		62,500	64,925	67,349	69,774	72,199
Core Commercial		3,370	3,411	3,513	3,735	3,784
Noncore Commercial		20	20	21	22	22
Noncore Industrial		10	10	10	10	10
Electric Generation		1	1	1	1	1
Total		65,901	68,367	70,894	73,542	76,016
Gas Requirements (Mth)						
Residential		20,600	21,293	21,977	22,655	23,395
Core Commercial		6,366	6,475	6,702	7,161	7,291
Noncore Commercial		5,000	5,086	5,264	5,625	5,727
Noncore Industrial		34,778	34,778	34,778	34,778	34,778
Subtotal R/C/I		66,744	67,632	68,721	70,219	71,191
Electric Generation		110,184	113,489	116,894	120,401	124,013
Total		176,928	181,121	185,615	190,620	195,204
% Increase			2.4%	2.5%	2.7%	2.4%
Estimated SDG&E Delivery Rates ($/Therm) (Including SoCalGas charges)						
Residential		0.394	0.429	0.436	0.443	0.451
Core Commercial		0.420	0.405	0.412	0.419	0.426
Noncore Commercial		0.078	0.088	0.089	0.091	0.092
Noncore Industrial		0.078	0.088	0.089	0.091	0.092
Electric Generation		0.019	0.027	0.047	0.048	0.049
change				*1.7%*	*1.7%*	*1.7%*
Estimated SDG&E Non-Gas Revenue ($000) (including SoCalGas charges)						
Residential		$8,112	$9,129	$9,580	$10,040	$10,541
Core Commercial		$2,671	$2,625	$2,762	$3,000	$3,106
Noncore Commercial		$388	$446	$469	$510	$528
Noncore Industrial		$2,700	$3,050	$3,101	$3,153	$3,206
Subtotal R/C/I		$13,871	$15,250	$15,912	$16,703	$17,381
Average R/C/I ($/Therm)		0.208	0.225	0.232	0.238	0.244
Electric Generation		$2,093	$3,118	$5,494	$5,753	$6,024
Total		$15,964	$18,368	$21,406	$22,456	$23,405
Averge ($/Therm)		$0.090	$0.101	$0.115	$0.118	$0.120
Estimated Chula Vista Operating Expenses (including charges to bypass SDG&E)						
C.V. Delivery Cost to R/C/I			0.152	0.157	0.161	0.166
C.V. Cost to Serve R/C/I ($000)			$10,294	$10,774	$11,339	$11,841
Est. Cost to Serve Power Plant ($/Th)			0.0010	0.0010	0.0011	0.0011
C.V. Cost to Serve PP ($000)	$1,998		$113	$120	$128	$136
Bypass Transmission Rate ($/Th)			0.014	0.014	0.014	0.015
Bypass Cost to C.V.			**$2,554**	**$2,617**	**$2,733**	**$2,845**
Capital Expense ($000)			$418	$418	$418	$418
Capital Improvement Cost ($000)			$958	$958	$958	$958
Total Expenses			$14,337	$14,887	$15,576	$16,198
Total $/Therm			0.079	0.080	0.082	0.083
Estimated Benefit of Gas Utility						
SDG&E Revenue minus CV Cost	$80,617		$4,031	$6,519	$6,881	$7,207
Lost Franchise Fee	$7,244		$657	$681	$689	$709
Net Benefit/(Cost)	**$73,373**		$3,374	$5,838	$6,192	$6,498
Discount Rate	9.73%					

Attachment B

City of Chula Vista
Financial Pro Forma Analysis
Natural Gas Utility Option
(SDG&E System Bypass)

	2007	2008	2009	2010	2011	2012
Customer Accounts						
Residential	74,624	76,643	78,663	80,683	81,248	81,813
Core Commercial	3,833	3,882	3,954	4,045	4,069	4,092
Noncore Commercial	23	23	23	24	24	24
Noncore Industrial	10	10	10	10	10	10
Electric Generation	1	1	1	1	1	1
Total	78,491	80,559	82,651	84,763	85,352	85,940
Gas Requirements (Mth)						
Residential	24,132	24,786	25,439	26,092	26,275	26,457
Core Commercial	7,422	7,556	7,734	7,952	8,038	8,125
Noncore Commercial	5,830	5,935	6,075	6,246	6,314	6,382
Noncore Industrial	34,778	34,778	34,778	34,778	34,778	34,778
Subtotal R/C/I	72,162	73,055	74,026	75,068	75,405	75,742
Electric Generation	0	0	257,544	257,544	257,544	257,544
Total	72,162	73,055	331,570	332,612	332,949	333,286
% Increase	-63.0%	1.2%	353.9%	0.3%	0.1%	0.1%
Estimated SDG&E Delivery Rates ($/Therm)						
Residential	0.458	0.466	0.473	0.481	0.489	0.497
Core Commercial	0.433	0.440	0.448	0.455	0.462	0.470
Noncore Commercial	0.094	0.095	0.097	0.098	0.100	0.102
Noncore Industrial	0.094	0.095	0.097	0.098	0.100	0.102
Electric Generation	0.049	0.050	0.051	0.052	0.053	0.054
change	*0.5%*	*3.4%*	*1.1%*	*1.7%*	*1.6%*	*1.6%*
Estimated SDG&E Non-Gas Revenue ($000)						
Residential	$11,054	$11,542	$12,043	$12,558	$12,850	$13,147
Core Commercial	$3,214	$3,327	$3,462	$3,618	$3,716	$3,817
Noncore Commercial	$546	$565	$588	$615	$632	$649
Noncore Industrial	$3,259	$3,313	$3,368	$3,424	$3,479	$3,535
Subtotal R/C/I	$18,073	$18,747	$19,461	$20,215	$20,677	$21,148
Average R/C/I ($/Therm)	0.250	0.257	0.263	0.269	0.274	0.279
Electric Generation	$0	$0	$13,145	$13,364	$13,579	$13,798
Total	$18,073	$18,747	$32,606	$33,579	$34,256	$34,946
Averge ($/Therm)	$0.250	$0.257	$0.098	$0.101	$0.103	$0.105
Estimated Chula Vista Operating Expenses						
C.V. Delivery Cost to R/C/I	0.171	0.176	0.182	0.187	0.193	0.199
C.V. Cost to Serve R/C/I ($000)	$12,363	$12,891	$13,454	$14,053	$14,539	$15,042
Est. Cost to Serve Power Plant ($/Th)	0.0011	0.0011	0.0012	0.0012	0.0013	0.0013
C.V. Cost to Serve PP ($000)	$0	$0	$308	$317	$326	$336
Bypass Transmission Rate ($/Th)	0.015	0.015	0.015	0.016	0.016	0.016
Bypass Cost to C.V.	**$1,056**	**$1,106**	**$5,077**	**$5,178**	**$5,267**	**$5,357**
Capital Expense ($000)	$418	$418	$418	$418	$418	$418
Capital Improvement Cost ($000)	$958	$958	$958	$958	$958	$958
Total Expenses	$14,795	$15,373	$20,215	$20,924	$21,508	$22,111
Total $/Therm	0.205	0.210	0.061	0.063	0.065	0.066
Estimated Benefit of Gas Utility						
SDG&E Revenue minus CV Cost	$3,278	$3,374	$12,391	$12,655	$12,749	$12,835
Lost Franchise Fee	$650	$679	$858	$885	$905	$924
Net Benefit/(Cost)	$2,628	$2,695	$11,533	$11,770	$11,844	$11,911
Discount Rate						

Attachment B

City of Chula Vista
Financial Pro Forma Analysis
Natural Gas Utility Option
(SDG&E System Bypass)

	2013	2014	2015	2016	2017	2018
Customer Accounts						
Residential	82,378	82,944	83,509	84,074	84,640	85,205
Core Commercial	4,116	4,190	4,377	4,413	4,449	4,485
Noncore Commercial	24	25	26	26	26	27
Noncore Industrial	10	10	10	10	10	10
Electric Generation	1	1	1	1	1	1
Total	86,529	87,170	87,923	88,524	89,126	89,728
Gas Requirements (Mth)						
Residential	26,640	26,823	27,006	27,189	27,371	27,554
Core Commercial	8,212	8,402	8,822	8,938	9,056	9,175
Noncore Commercial	6,450	6,600	6,930	7,021	7,113	7,207
Noncore Industrial	34,778	34,778	34,778	34,778	34,778	34,778
Subtotal R/C/I	76,080	76,603	77,536	77,926	78,318	78,714
Electric Generation	257,544	257,544	257,544	257,544	257,544	257,544
Total	333,624	334,147	335,080	335,470	335,862	336,258
% Increase	0.1%	0.2%	0.3%	0.1%	0.1%	0.1%
Estimated SDG&E Delivery Rates ($/Therm)						
Residential	0.505	0.513	0.521	0.530	0.538	0.547
Core Commercial	0.477	0.485	0.493	0.501	0.509	0.517
Noncore Commercial	0.103	0.105	0.107	0.108	0.110	0.112
Noncore Industrial	0.103	0.105	0.107	0.108	0.110	0.112
Electric Generation	0.054	0.055	0.056	0.057	0.058	0.059
change	*1.6%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*
Estimated SDG&E Non-Gas Revenue ($000)						
Residential	$13,451	$13,761	$14,078	$14,401	$14,730	$15,067
Core Commercial	$3,920	$4,075	$4,348	$4,476	$4,607	$4,743
Noncore Commercial	$666	$693	$739	$761	$783	$806
Noncore Industrial	$3,592	$3,650	$3,709	$3,768	$3,829	$3,890
Subtotal R/C/I	$21,629	$22,179	$22,874	$23,406	$23,949	$24,506
Average R/C/I ($/Therm)	0.284	0.290	0.295	0.300	0.306	0.311
Electric Generation	$14,020	$14,246	$14,475	$14,707	$14,942	$15,183
Total	$35,649	$36,425	$37,349	$38,113	$38,891	$39,689
Averge ($/Therm)	$0.107	$0.109	$0.111	$0.114	$0.116	$0.118
Estimated Chula Vista Operating Expenses						
C.V. Delivery Cost to R/C/I	0.205	0.211	0.217	0.224	0.230	0.237
C.V. Cost to Serve R/C/I ($000)	$15,563	$16,140	$16,827	$17,418	$18,031	$18,666
Est. Cost to Serve Power Plant ($/Th)	0.0013	0.0014	0.0014	0.0015	0.0015	0.0016
C.V. Cost to Serve PP ($000)	$346	$357	$367	$378	$390	$401
Bypass Transmission Rate ($/Th)	0.016	0.017	0.017	0.017	0.017	0.018
Bypass Cost to C.V.	**$5,449**	**$5,545**	**$5,650**	**$5,747**	**$5,846**	**$5,947**
Capital Expense ($000)	$418	$418	$418	$418	$418	$418
Capital Improvement Cost ($000)	$958	$958	$958	$958	$958	$958
Total Expenses	$22,734	$23,418	$24,220	$24,919	$25,643	$26,390
Total $/Therm	0.068	0.070	0.072	0.074	0.076	0.078
Estimated Benefit of Gas Utility						
SDG&E Revenue minus CV Cost	$12,916	$13,007	$13,129	$13,194	$13,248	$13,299
Lost Franchise Fee	$938	$956	$978	$989	$1,002	$1,031
Net Benefit/(Cost)	$11,978	$12,051	$12,151	$12,205	$12,246	$12,268
Discount Rate						

Attachment B

City of Chula Vista
Financial Pro Forma Analysis
Natural Gas Utility Option
(SDG&E System Bypass)

	2019	2020	2021	2022	2023
Customer Accounts					
Residential	85,770	86,335	86,496	86,656	86,816
Core Commercial	4,521	4,556	4,599	4,642	4,685
Noncore Commercial	27	27	27	28	28
Noncore Industrial	10	10	10	10	10
Electric Generation	1	1	1	1	1
Total	90,329	90,929	91,133	91,337	91,540
Gas Requirements (Mth)					
Residential	27,737	27,920	27,972	28,023	28,075
Core Commercial	9,295	9,414	9,550	9,687	9,827
Noncore Commercial	7,301	7,395	7,501	7,609	7,719
Noncore Industrial	34,778	34,778	34,778	34,778	34,778
Subtotal R/C/I	79,111	79,507	79,801	80,097	80,399
Electric Generation	257,544	257,544	257,544	257,544	257,544
Total	336,655	337,051	337,345	337,641	337,943
% Increase	0.1%	0.1%	0.1%	0.1%	0.1%
Estimated SDG&E Delivery Rates ($/Therm)					
Residential	0.556	0.564	0.574	0.583	0.592
Core Commercial	0.525	0.534	0.542	0.551	0.560
Noncore Commercial	0.114	0.115	0.117	0.119	0.121
Noncore Industrial	0.114	0.115	0.117	0.119	0.121
Electric Generation	0.060	0.061	0.062	0.063	0.064
change	*1.6%*	*1.6%*	*1.6%*	*1.6%*	*1.6%*
Estimated SDG&E Non-Gas Revenue ($000)					
Residential	$15,410	$15,760	$16,042	$16,329	$16,621
Core Commercial	$4,882	$5,024	$5,178	$5,336	$5,500
Noncore Commercial	$830	$854	$880	$907	$935
Noncore Industrial	$3,953	$4,016	$4,080	$4,146	$4,212
Subtotal R/C/I	$25,075	$25,654	$26,180	$26,718	$27,268
Average R/C/I ($/Therm)	0.317	0.323	0.328	0.334	0.339
Electric Generation	$15,425	$15,673	$15,923	$16,179	$16,438
Total	$40,500	$41,327	$42,103	$42,897	$43,706
Averge ($/Therm)	$0.120	$0.123	$0.125	$0.127	$0.129
Estimated Chula Vista Operating Expenses					
C.V. Delivery Cost to R/C/I	0.244	0.252	0.259	0.267	0.275
C.V. Cost to Serve R/C/I ($000)	$19,323	$20,002	$20,679	$21,378	$22,102
Est. Cost to Serve Power Plant ($/Th)	0.0016	0.0017	0.0017	0.0018	0.0018
C.V. Cost to Serve PP ($000)	$413	$426	$438	$452	$465
Bypass Transmission Rate ($/Th)	0.018	0.018	0.019	0.019	0.019
Bypass Cost to C.V.	**$6,049**	**$6,153**	**$6,257**	**$6,363**	**$6,471**
Capital Expense ($000)	$418	$418	$418	$418	$418
Capital Improvement Cost ($000)	$958	$958	$958	$958	$958
Total Expenses	$27,161	$27,957	$28,750	$29,569	$30,414
Total $/Therm	0.081	0.083	0.085	0.088	0.090
Estimated Benefit of Gas Utility					
SDG&E Revenue minus CV Cost	$13,339	$13,369	$13,353	$13,328	$13,292
Lost Franchise Fee	$1,055	$1,078	$1,104	$1,133	$1,146
Net Benefit/(Cost)	$12,284	$12,291	$12,249	$12,195	$12,146
Discount Rate					